



American Public Power Association

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September 21, 2005

BY ELECTRONIC MAIL

David H. Meyer
Acting Deputy Director
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United States Department of Energy
Washington, D.C. 20585

Re: Questions Regarding Economic Dispatch of Generation

Dear Mr. Meyer:

The American Public Power Association (“APPA”) is providing this response to your letter of September 6, 2005, regarding the study on economic dispatch of electric generation required by Section 1234 of the Energy Policy Act of 2005.

As you requested, APPA circulated your letter and the attached survey questions among its membership via its electronic list serves, notifying them that the U.S. Department of Energy (“DOE”) was requesting their assistance. We anticipate that members will respond to DOE directly regarding their own views on how economic dispatch is carried out in their regions. Hence, APPA in this response is not attempting to provide a region-by-region overview of the industry’s economic dispatch practices or respond to all of the specific questions attached to your letter. APPA, however, does wish to provide DOE with the following views and information, in the hopes that it will serve as useful background material as DOE prepares the study Congress has mandated.

First, the definition of economic dispatch set out in Section 1234 is quite generic, and hence subject to varying interpretations. The definition refers to the operation of generation facilities “at the lowest cost.” But it is not clear whether the word “cost” means the cost of production of each unit dispatched (in other words, what is referred to in the industry as a “cost-based dispatch”) or a dispatch regime under which each generation unit is bid by its operator into a centralized market at a price that the owner sets at its discretion (subject only to any applicable market rules), which is generally known as a “bid-based dispatch.” The former type

of dispatch was a central feature of a number of regional power pools that the electric utility industry operated prior to restructuring, with utilities bidding in their generation at cost, resulting in savings from such joint operations that were shared among the members, often under a “split the savings” convention. The latter type of dispatch is now in use in a number of organized markets run by Regional Transmission Organizations (“RTOs”) and Independent Systems Operators (“ISOs”), including ISO New England, the PJM Interconnection, the New York ISO and the Midwest ISO. These ISOs run day-ahead and real-time markets using a security-constrained, bid-based economic dispatch and a single-clearing price mechanism. Under the single-clearing price convention, all generators bidding into the market for a particular time interval are paid the price necessary to clear the market in that time interval, even if the bid a chosen generator made was much lower than that clearing price.

Prior to restructuring, many APPA members participated in regional power pools run using a cost-based economic dispatch (and some still do). They realized substantial savings for their consumers as a result. This, however, generally has not proved to be the case with the centralized, bid-based markets that ISOs now run. Enclosed as Attachment 1 is an interview with Bill Gallagher, the General Manager of the Vermont Public Power Supply Authority and the current Chairman of the Board of APPA, in the September-October 2005 issue of *Public Power* magazine, in which he discusses the consequences for consumers when a cost-based dispatch system is replaced by a bid-based system. He recounts in the interview the transformation of the New England Power Pool (“NEPOOL”) from a tight power pool operated using a security-constrained cost-based dispatch (at an annual pool operations cost of \$14 million) to a bid-based, security-constrained, single-price clearing market operated by ISO New England (at an annual operations cost of \$140 million). As he explains, owners of deregulated nuclear plants in New England (on which ratepayers have already paid stranded costs) are now receiving single-clearing prices of \$70 per megawatt-hour (“MWh”) (set by high-cost natural gas units) when their plants are on the books for two cents a kilowatt-hour for capacity and energy.¹ New England ratepayers will eventually pay the difference.

¹ Recent trade press reports bear these figures out. As reported in the August 29, 2005 issue of *Electric Utility Week*, at page 12, median coal-generation spark spreads (the margin between prevailing market prices and generation costs) were \$59 per MWh in New England and \$45 per MWh in PJM.

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At the same time, units with high operating costs are often able to recover their costs outside of such markets through devices such as “Reliability Must Run” (“RMR”) contracts. The end result can be a “higher of cost or market” regime that does not constitute true competition, and raises generation costs to consumers higher than anyone anticipated when restructuring was originally proposed. One APPA member in New England, the Connecticut Municipal Electric Energy Cooperative, filed a complaint against ISO New England with the Federal Energy Regulatory Commission (“FERC”) on September 12, 2005, in Docket No. EL05-150 jointly with a number of other entities in Connecticut, raising such pricing issues. The complaint alleges that ISO New England’s overall pricing regime in Connecticut produces unjust and unreasonable wholesale electric prices, in violation of the Federal Power Act. A copy of that complaint is enclosed as Attachment 2 for DOE’s information.

APPA members have also discovered that the high clearing prices set in ISO-run day-ahead and real-time markets (which are often set based on the high fuel cost of natural gas-fired generation units) are having a “ripple effect” on longer-term bilateral markets. At APPA’s June 2005 National Conference in Anaheim, California, the membership passed Resolution 05-18, entitled “Unjust and Unreasonable Prices for Long Term Bilateral Power Supplies” (copy enclosed as Attachment 3). That resolution notes that:

APPA members in RTO regions that attempt to procure power under long-term bilateral arrangements now find that generators are often willing to enter into such agreements only on terms that reflect the (higher) “market clearing prices” they can obtain in RTO-run spot markets, even when their own (lower) costs structures bear little relationship to spot market clearing prices.

Because such APPA members rely on bilateral power supply contracts to avoid the even higher risk and price volatility of spot markets, this perverse pricing “feedback loop” has caused steep retail rate increases in some public power communities.

Even a “pure” cost-based economic dispatch of generation across a region can raise difficult questions. For example, some generation resources, such as storage-limited hydroelectric resources or environmentally limited fossil fuel plants, incur opportunity costs if they are required to run at a time not of their own choosing. These costs can be quite difficult to value. Operators must also account for regulatory and contractual limitations on unit operations, level of fuel inventories, transmission constraints, low load stability risk, ramp requirements, weather conditions, and other factors.

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But these pricing and operational issues with cost-based dispatch are dwarfed by the problems APPA members are experiencing with ISO-run, bid-based, single-clearing price markets. APPA understands the economic theory underpinning this market model, and its attraction to policy makers. But for this model to work, the bids of generators must reflect the true marginal cost of producing the last unit of electric power. For many reasons, including substantial transmission constraints, unanticipated increases in natural gas prices that have weakened new generation entrants heavily dependent on that fuel, convoluted market rules and associated exceptions, generation market power, and concomitant economic withholding, the actual results in bid-based markets have diverged markedly from the theory of how a competitive market should work, to the detriment of electric consumers.

For these reasons, APPA does not support the further extension of ISO-run, bid-based single-clearing price markets to regions of the country that do not now have them. Further explanation of APPA's general position can be found in APPA's December 2004 policy paper, "Restructuring at the Crossroads: FERC Transmission Policy Reconsidered," which is enclosed as Attachment 4.

We hope that this information is helpful to DOE as it prepares its study. If you have further questions, please do not hesitate to contact one of us.

Very truly yours,

/s/

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Enclosures (4)

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